NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Minutes
Frequency Response Initiative Meeting

April 27, 2010
Tucson Electric Co. Office
Tucson, Arizona

A meeting of the NERC Frequency Response Initiative Team was held on April 27, 2010 at the Ameren Corporation Office in St. Louis, Missouri. The agenda, and attendance list are attached as **Exhibits A** and **B**, respectively. There are no individual statements or minority opinions.

Bob Cummings, NERC Director of System Analysis and Reliability Initiatives presided over the meeting.

NERC Frequency Response Initiative Appreciation for Meeting Host Ameren Corporation

The Frequency Response Initiative Team acknowledges and appreciates the hospitality that the Ameren Corporation and specifically Gerry Beckerle and Crystal Ward provided to the subcommittee as it hosted the Frequency Response Initiative meeting at their facility.

Antitrust Compliance Guidelines

Director Bob Cummings acknowledged the NERC Antitrust Compliance Guidelines.

Frequency Response Initiative Terminology

The Frequency Response Initiative Team reviewed the current and proposed frequency related terms, definitions, and frequency events and recovery sequence of events. The team discussed and drafted terminology to be used by the electric power industry for common understanding and use, see (**Exhibit C)**.

Frequency Response Initiative Surveys

The Frequency Response Initiative Team will develop at least two surveys to gather data and information to support the frequency response analysis, conclusion, and recommendations. The two identified surveys are:

- Survey to attain knowledge on how Balancing Authorities calculate their frequency response. This survey will be completed in three months.
- Survey to attain generating unit(s) governor use, control, settings, and characteristics. This survey will be completed in six months.

The Frequency Response Initiative Survey Development Team will include the following:

- Bob Cummings
- Terry Bilke
- Sydney Niemeyer
- Bill Herbsleb
- Don Badley
- John Tolo
- Mike Potishnak
- Gerry Beckerle
- Larry Akens

Frequency Response Initiative Overview

Bob Cummings took all information attained and combined it with his previously developed initiative criteria and developed an enhanced "Overview of the Frequency Response Initiative." The "Overview" will be presented to the NERC Board of Trustees at the May 2010 meeting.

Key sections of the Overview are:

Introduction
Objectives of the Initiative
Initiative Tasks
Near-Term Tasks – expected to be completed in six months
Mid-Term Tasks – expected to be completed in nine months
Long-Term Tasks – expected to be completed in one to wwo years
Ongoing Tasks
Frequency Response and Control Terminology

Dates and Locations of Future Meetings

Additional meetings or conference calls may be scheduled as necessary for ADITF business-related purposes.

Tuesday, May 4, 2010 Wednesday, May 5, 2010	10 a.m. – 5 p.m. 8 a.m. – 5 p.m.	Chicago, IL Host: NERC Contact: Darrel Richardson

Respectfully submitted,

Tom Vandervort

Thomas J. Vandervort
Resources Subcommittee Secretary

Exhibit A

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Agenda
Frequency Response Initiative

April 27, 2010
St. Louis, Missouri

1. **Introductions**
   What is MINASPIFRISPI?

2. **Anti Trust Guidelines**

3. **Agenda Review**

4. **Freqeuency Response Initiative Overview**
   a. Initiative Tasks – are there others?
   b. Task Responsibilities – which group(s) have the lead?
   c. BAL-003 Request for Rehearing

5. **Terminology**
   Catalogue common terminology to be used in FRI

6. **Drafting Team Updates**

7. **Recommendation Alert**
   a. Discuss elements to be included in the Alert
   b. Schedule of the Alert

8. **Detailed Review of FRI Tasks**

Near-Term Tasks – Completed in Six Months

1. Issue a Recommendation and a survey in accordance with Section 810 of NERC's Rules of Procedure to in order to collect data to evaluate how frequency response should be addressed.
2. Based on the data received, analyze current and historical primary control frequency response performance and determine what factors influence that performance.

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3. Based on the data received, analyze current and historical secondary control performance and determine what factors influence that performance.
4. Develop an automated method for determining frequency deviation events that should be used for Balancing Authorities to determine their primary control frequency Response.
5. Develop sustainable methods for automatically collecting, trending, and analyzing the various elements of frequency response and control.
6. Improve transient and mid-term dynamic models of generator primary frequency response.

Long-Term Tasks – Completed in One Year

1. Explore and analyze what are appropriate frequency response and control performance requirements to maintain system reliability.
2. Determine appropriate minimum Bias settings for use in AGC systems as part of an overall frequency response and control strategy.
3. Analyze current Inertial Response performance and determine what factors influence that performance.
4. Explore how displacement of inertial generation with electronically-coupled resources might influence Inertial Response.
5. Examine Primary Control Frequency Response characteristics of electronically-coupled resources and “smart grid” loads. Appropriate load and “generator” models must be developed to properly analyze their influence on system behavior in transient, post-transient, and mid-term stability.

9. Future Meetings & Schedule

Exhibit B

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Meeting Notes
NERC Frequency Response Initiative

April 27, 2010
Ameren General Office Building
St. Louis, Missouri 63103

Attendance
David Hilt
Robert Cummings
Terry Bilke
Bill Herbsleb
Steve Myers
Howard Illian
Darrel Richardson
Doug Hils
Sydney Niemeyer
Tony Nguyen
Don Badley
John Tolo
Jerry Rust
Mark Prosperi-Porta
Phil Tatro
Larry Akens
LeRoy Patterson
Carlos Martinez
Mike Potishnak
Tom Siegrist
Mike Oatts
Glenn Stephens
Steve Crutchfield
Gerry Beckerle
Andy Rodriquez
James Murphy
Mahmood Mirheydar
Robert Rhodes
Tom Vandervort

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Exhibit C

Frequency Response Initiative
Draft Terminology as of 04–29–10

Frequency Response and Control – This is the over-arching descriptor for the response and control actions that span from when a frequency deviation begins until frequency is recovered.

Point *A* – The first significant change in frequency of a frequency event, which occurs at time zero (Scan *T*). A "significant" change in frequency is defined as: ±36 mHz for the Eastern Interconnection, ±50 mHz for the Western Interconnection, ±70 mHz for the Texas Interconnection, and ±__ mHz for the Quebec Interconnection.

Initial Frequency – (Value *A*) – The average actual (not scheduled) pre-perturbation frequency. Value *A* is defined as the average frequency prior to Point *A* based on a sample of 10 to 16 seconds, depending on the EMS Scan Rate of the BA as shown below, where *T* is the first scan that defines Point *A*.

EMS Scan Rate (seconds)	Scans Used to Determine Value *A*	# of Seconds in Sample
6 s	*T* minus 1 through *T* minus 2	12
5 s	*T* minus 1 through *T* minus 2	10
4 s	*T* minus 1 through *T* minus 8	12
3 s	*T* minus 1 through *T* minus 5	15
2 s	*T* minus 1 through *T* minus 8	16

Arrested Frequency – Value *C* – Point *C* – The point of lowest frequency in the first swing of the frequency excursion between time zero (Point *A*) and time zero plus 20 seconds.

Arresting Period – The period of time from time zero (Point *A*) to the time of Point *C*.

Arresting Period Frequency Response – A combination of Inertial Response and the initial Primary Control Response acting together to limit the duration and magnitude of frequency change during the Arresting Period. At Point *A*, the entire response is inertial, and by Point *C* (where

equilibrium has been established and frequency arrested), the inertial contribution is at zero. Depending on the type of trip, (e.g., an instantaneous electrical trip of the generator; or a turbine trip, where the generator trips at a later time after by reverse power; or other time tripping), the Primary Control Response may be initiated and contributing to the Arresting Period Frequency Response at Point *C*.

Rebound Period – The period of time from the time of Point *C* to time zero plus 20 seconds.

Rebound Period Frequency Response – The remaining portion of Primary Control Response delivered during the Rebound Period without any external intervention. During the Rebound Period, Primary Control Response begins to restore inertia expended as Inertial Response. The Rebound Period Frequency Response generally does not include Secondary Control Response, as typical Secondary Control performance occurs more than 35 to 40 seconds following Point *A*. In order to avoid the possibility of creating control-based instability, Automatic Secondary Control Response (such as AGC) should not be applied until the Primary Control Response has stabilized.

Settling Period – The period of time from the time of Point *C* to the time of Point *B*. Point *B* – The point at which Primary Control Response has been damped (stabilized).

Settled Frequency – Value B – The average actual (not scheduled) frequency following the Arresting Period. Value B is defined as the average frequency following Point C based on a sample of 28 to 34 seconds, depending on the EMS Scan Rate of the BA as shown below, where T is the first scan that defines Point *A*.

EMS Scan Rate (seconds)	Scans Used to Determine Value *A*	# of Seconds in Sample
6 s	*T* plus 4 through *T* plus 8	30
5 s	*T* plus 5 through *T* plus 10	30
4 s	*T* plus 6 through *T* plus 12	28
3 s	*T* plus 7 through *T* plus 17	33
2 s	*T* plus 10 through *T* plus 26	34

Recovery Period – The period of time from time zero plus 53 seconds to the time of the return of frequency to within pre-establish ranges of reliable continuous operation.

Primary Control – Actions provided by the Interconnection to arrest frequency in response to a frequency event (disturbance). Primary Control comes from generator governor response, load

response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Control – Actions provided by an individual BA or its Reserve Sharing Group intended to replace Primary Control Response and restore frequency from the Arrested Frequency back to Scheduled Frequency. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Control – Actions provided by Balancing Authorities on a balanced basis that are expected to have a net zero effect on ACE. Examples of Tertiary Control include dispatching generation to serve native load; dispatching generation to effect Interchange; and redispatching generation.

Inertial Response – The power delivered by the Interconnection in response to any change in frequency due to the rotating mass of machines synchronously connected to the BPS, including both load and generation.

Primary Control Response – The power delivered by the Interconnection in response to a frequency event (disturbance) through generator governor response, load response (typically from motors), and other devices that provide an immediate response to frequency based on local (device-level) control systems, without human or remote intervention.

Primary Control Response Withdrawal – The withdrawal of previously delivered Primary Control Response, either through local Primary Control actions (such as plant internal control) or though Secondary Control action (such as AGC).

Secondary Control Response – The power delivered by a Balancing Authority or Reserve Sharing Group in response to a frequency event (disturbance) through Secondary Control actions, such as manual or automated dispatch from a centralized control system. Secondary control actions are intended to replace Primary Control Response and restore frequency from the Arrested Frequency back to Scheduled Frequency.

Recovery of Frequency Responsive Reserves – This is the redispatch of generation and scheduling of interchange to recover the required frequency responsive reserves of the interconnection in preparation for the next event.